COMMENTS OF GENERAL ELECTRIC COMPANY

ON

EPA'S DIRECT FINAL RULE: AMENDMENTS TO STANDARDS OF PERFORMANCE FOR STATIONARY GAS TURBINES

Docket No. OAR-2002-0053

General Electric Company (GE) submits the following comments on the Direct Final Rule, Amendments to the New Source Performance Standards for Stationary Gas Turbines, 68 *Fed. Reg.* 17990 (April 14, 2003). GE is a diversified services, technology and manufacturing company with a commitment to achieving customer success, innovation, and worldwide leadership in each of its businesses. GE operates in more than 100 countries and employs more than 300,000 people worldwide. The proposed rule would affect many of the products of GE's Power Systems unit (GEPS), as well as certain products of GE's Aircraft Engines unit (GEAE) and some of GE's manufacturing facilities.

GEPS provides a wide array of services and products designed to meet world demand for abundant, reliable and efficient energy. Among GEPS products are combustion turbines (CTs), ranging in size from 5 MW up to 190 MW. These CTs, including GE's Lean Pre-Mix turbines are among the very cleanest sources of electric power and other useable forms of energy available, and they are the most efficient means of generating electricity from fossil fuels commercially available. In addition, GE manufactures packaged power units that combine generators with CTs manufactured by GEAE for customers with a need for distributed power. Like GEPS large frame CTs, these aeroderivative products are among the most efficient and cleanest power generating units of their kind. GE refers to its lean pre-mix technology for the heavy-duty frame units as Dry Low NOx, or DLN, and refers to turbines using this technology as DLNs. For the aero-derivative, or LM units, the lean premix technology is referred to as Dry Low Emissions, or DLE.

1. §60.331(a) - The definition of "stationary gas turbine" should include all the associated critical systems.

A facility can trigger compliance with the New Source Review requirements at an existing source, if it undertakes "reconstruction" of that source. The test for "reconstruction" includes a calculation of the amount of the fixed capital cost it would take to replace the unit. Thus, defining the unit is critical.

GE suggests that EPA broaden the definition of stationary gas turbine system in §60.331(a) to include additional components, consistent with EPA's intent for the concept of reconstruction. In 1975, EPA stated that the term "fixed capital cost" is broadly construed to include all "the capital needed to provide all the depreciable components and is intended to include such things as the costs of engineering, purchase, and installation of major process equipment, contractors' fees, instrumentation, auxiliary facilities, buildings, and structures... " (40 FR 58416, December 16, 1975). The rule relating to Routine Maintenance, Repair and Replacement proposed at 67 FR 80290, December 31, 2002, also includes triggers for New Source Review that are a function of facility replacement cost. Consequently, GE recommends that EPA define "stationary gas turbine" as follows:

> "A stationary gas turbine includes all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems; control systems; and any ancillary components and sub-components comprising any simple cycle stationary gas turbine; any regenerative/recuperative cycle stationary gas turbine; the gas turbine portion of any stationary cogeneration cycle combustion system; or the gas turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the gas turbine is not self-propelled, nor is it intended to be propelled, while performing its function. However, it may be mounted on a vehicle for portability."

2. §60.331(e) - The definition of "Emergency Turbines" should be clarified and broadened.

An emergency turbine is defined at §60.331(e) as "any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation." For some facilities the power emergency may only affect a portion of the facility not the entire facility (i.e. a building or factory). The definition should be broadened such that it recognizes the emergency turbine function for situations where power failures do not affect an entire facility.

Furthermore, operation of "emergency turbines" should not be limited to only those times when the primary power source has been rendered inoperable by an emergency situation. EPA should include more examples of emergency operation in the emergency use definition. These might include fuel and raw material curtailments that require the operation of a standby stationary gas turbine, for example, a power boiler whose supply of a process byproduct used as a boiler fuel has been cut off, or a coal-fired boiler whose coal supply system undergoes a mechanical failure. Such periods of operation are unpredictable and beyond the control of the owner/operator, but it might be argued by some not to be within the realm of emergency operations. The final rule should be clarified to state that fuel curtailments are considered emergencies. This would make it consistent with the definition of emergency fuel in §60.331(r).

3. §60.331(v) – In the definition of natural gas, the total sulfur is limited to 20 grains of sulfur per 100 standard cubic feet. Pipeline natural gas generally contains less than 20 grains of sulfur per 100 cubic-feet, however, mercaptans, which are sulfur-containing compounds, are typically added as an odorizer. Does the 20-grain limit in the definition account for the sulfur in mercaptans or other odorizers? If the gas contains more than 20 grains per 100 standard cubic feet,

does that mean it is not natural gas? EPA should make it clear that the 20 grains per 100 standard cubic feet is not a limit, but rather is typical of pipeline natural gas in the U.S.

4. §60.331(x) - The definition of "Lean premix stationary combustion turbines" needs clarification.

A lean premix stationary combustion turbine is defined in §60.331(x) as "any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor." However, this definition fails to recognize that the mixing of air and fuel in some cases may take place in an area normally interpreted to be part of the combustor. For example in the GE gas turbines known as DLN-1, there are two stages in the combustion chamber. The function of first stage is to thoroughly mix the fuel and air and to provide a uniform, lean, unburned fuel-air mixture to the second stage where the combustion takes place. The definition should be clarified to state ".... any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before combustion. Lean premixed combustion has a flamefront between the incoming premixed fuel/air mixture and combusted gases."

5. §60.331(y) - The definition of "diffusion flame stationary combustion turbine" should be clarified and broadened.

A diffusion flame stationary combustion turbine is defined in §60.331(y) as "any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition." The proposed definition should be clarified by stating that a diffusion flame combustor is one where the fuel and the air/oxygen reach the flame front by 'diffusion' or, in other words, the flame front is located between zones rich in fuel and zones rich in oxidant (air). In addition, it should be broadened to recognize that swirl cups, nozzles or orifice mixers are used to provide fuel and air mixing in some diffusion flame combustors. Although these devices mix the air and fuel prior to combustion they clearly do not fall within the "lean premix" definition. The diffusion flame stationary combustion turbine definition should be modified to read, "Diffusion flame stationary combustion turbine means any stationary combustion turbine where the fuel and the air/oxygen in the combustor reach the flame front by 'diffusion'. The flame front is located between zones rich in fuel and zones rich in oxidant (air). Mixing of the fuel and air at the combustor may be enhanced through the use of mechanical devices such as swirl cups, nozzles or orifices prior to ignition."

6. §60.334(j)(1)(i)(A)-The requirement that "Any unit operating hour in which no water or steam is injected into the turbine shall also be considered a deviation" does not appear to exempt startup or shutdown transients. For diffusion flame combustion units and lean premix units firing oil, steam or water injection usually is initiated between 20-50% of base load during startup and is likewise discontinued during the shutdown transient. Without exempting the startup and shutdown transients, any gas turbine equipped with steam or water injection for NOx control would always have a "deviation" during these transients.

7. §60.335(b)(1) - The equation for correcting measured NOx concentration to ISO standard conditions has no technical basis for use with lean, premix combustion gas turbines.

There is no technical basis for the use of the NOx ISO correction equation in §60.335(b)(1) for gas turbines with lean, premix combustors or for diffusion flame combustors with injection of steam or water to NOx levels significantly below the NSPS level of 75 ppm. The Subpart GG ISO Correction equation was derived as a consensus empirical fit of data available from water/steam injected diffusion flame combustors in the early 1970s at NOx levels of 75 ppmvd and higher. There is no basis for concluding that it applies to NOx levels significantly below 75 ppmvd, as is the case for today's gas turbine emission limits. Furthermore, it physically does not represent the relationship of parameters for lean premixed combustors at any NOx level and no comparable general relationship has been derived for premixed combustors. Thus, it is may be inappropriate to use the ISO Correction equation in Subpart GG of 40CFR60 for diffusion combustors significantly below a NOx emission level of 75 ppm, or for premixed combustors at any NOx level.

The equation:

$$NOx = [NOxo][Pr/Po]^{0.5} e^{19(Ho - 0.00633)} [288^{\circ}K/Ta]^{1.53}$$

Where:

NOx = emission concentration of NOx at 15 percent O_2 and ISO standard ambient conditions, ppm by volume, dry basis,

NOxo = observed NOx concentration ppm by volume, dry basis at 15 percent O_2 , corrected using either EPA Method 20 or Method 3 or 3A data,

Pr = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

Po = observed combustor inlet absolute pressure at test, mm Hg,

Ho = observed humidity of ambient air, g H_2O/g air
E = transcendental constant, 2.718, and

Ta = ambient temperature, °K

Making use of the equation optional for lean, premix combustors begs the question of whether there is any basis for the use of the equation for anything but water injected, diffusion flame combustion gas turbines at NOx levels of 75 ppm and higher.

GE interprets the wording in this section to mean that no correction is required if the option is chosen by the owner to not use the above correction equation for "lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices" such as SCR.

8. §60.335(b)(1) – The EPA, in a policy letter from Bruce Jordon, Director Emissions Standards Division, dated June 2, 1997 approved the use of GE's gas turbine control algorithm in lieu of the Subpart GG ISO correction equation for GE diffusion flame combustion, heavy duty (frame) gas turbines requiring either water or steam injection for NOx abatement. The Agency has accepted this alternative protocol in lieu of the static water-to-fuel ratio curve generated during performance tests. GE offered this alternative approach since its water injection rate is varied in accordance with atmospheric conditions.

9. §60.335(b)(3)- The option to measure gas turbine NOx emissions in the exhaust stream "after the duct burner rather than directly after the turbine" is not viable as written. The rule change provides that the duct burner's measured NOx contribution will be eliminated, i.e., no additional NOx allowance will be provided for the duct burner NOx contribution, if this option is used. This change does not appear to be based on actual combined cycle operating experience. Duct burners contribute measured amounts of NOx emissions, especially on oil firing. To make this option viable, the "no allowance clause" should be changed to provide for the duct burner NOx contribution. GE strongly believes that the proposed option, to measure gas turbine NOx emissions "after the duct burner rather than directly after the turbine", is not viable without accounting for this additional NOx contribution.

Where duct burners are used, new combined-cycle units are subject to two separate New Source Performance Standards (NSPS). The gas turbine portion of the units will be subject to 40 CFR Part 60, Subpart GG for stationary gas turbines, just like a simple-cycle turbine. The duct burners, which provide supplemental heat input to the HRSG, however, will be subject to the requirements of 40 CFR Part 60, Subpart Da or Db. Subpart Da applies to new electric utility units capable of combusting more than 250 mmBtu/hour heat input of fossil fuel in the steam generator, while Subpart Db, applies to smaller industrial units. Subparts Da, Db and GG all establish emission limitations, along with performance testing and monitoring requirements.

Under Subparts Da and Db, each boiler used to produce steam, including the HRSG in a combined-cycle gas turbine, is treated as a separate unit. However, only those emissions "resulting from combustion of fuels in the steam generating unit" are subject to Subpart Da (or Db). The emissions from the gas turbine that are exhausted into the HRSG are not subject to Subpart Da (or Db), but only to Subpart GG.

The Subpart Da NO_x limitation for new sources constructed after July 9, 1997 is 1.6 lbs/MW-hour gross energy output, based on a 30-day rolling average. Sources are required to install a NO_x CEM to calculate NO_x emissions for determining compliance. The NO_x emissions from the HRSG duct burners are calculated using the appropriate equations in Method 19 to subtract the gas turbine's NO_x emissions from the total NO_x emissions measured in the stack during the Subpart GG gas turbine performance tests.

10. 40 CFR 75 requirements rather than 40 CFR 60 requirements for the 7-day drift test should apply for units that operate only periodically, such as peaking gas turbines.

The 7-day drift test required in 40 CFR 60 is unnecessary and may be unrepresentative for units that operate only periodically. The rule requires that all units must perform a 7-day calibration error test on seven consecutive operating days and the test must be performed while the unit is "on-line." This requirement is particularly difficult for infrequently operated units. Long periods of time with a unit shut down may pass during the seven operating days and drift, particularly in the presence of unit instability, may be practically unavoidable. The stack exhaust temperature for simple-cycle turbines, which represent a large portion of peaking units, is approximately 1000°F, and some CEM systems would not be able to pass one calibration under such operating temperatures and then pass the next under ambient conditions. GE recommends that the EPA should delete the 7-day drift test requirement, if not for all units, then certainly for gas turbines that operate infrequently. A drift test in the form of a daily calibration error test is done every day and these tests are more than adequate to bring potential drift problems to the attention of CEMS technicians. Part 75 allows the time to be considered to be continuous even with interruptions.

11. Part 75 exempts gas turbines firing natural gas, or less than 10% oil, from opacity monitoring. This exemption reflects the truly negligible amount of particulate produced by turbines resulting from the nature of the fuels fired and the particulars of the combustion process. However, many, if not most, states are incorporating opacity or particulate limits with periodic monitoring requirements, generally Method 9, into permits for new gas turbines. These permit conditions requiring an opacity meter are unnecessary and should be avoided except in a case-by-case situation where either more than 10% oil is used, or an unusual fuel (e.g., high ash) is used.